EXHIBIT

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INTRODUCTION – STATEMENT OF QUALIFICATION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dante Mugrace. My business address is 22 Brookes Avenue, Gaithersburg, MD 20877.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a Senior Consultant with the Economic and Management Consultant Firm of PCMG and Associates, LLC. (PCMG). In my capacity as a Senior Consultant, I am responsible for evaluating and examining rate and rate-related proceedings before various governmental entities, preparing expert testimony and reviewing and making recommendations concerning revenue requirement proposals, as well as, offering opinions on economic policy and policy issues and methodologies used to set a value on a utility's rate base and cost of service components of revenue requirements.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE?

A. PCMG is an association of experts in the area of utility regulation and policy, economics, accounting, and finance. PCMG's members have over 75 years of collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water and wastewater utilities that operate under local, state, and federal jurisdictions. PCMG brings to client engagements a consultative and collaborative approach to the identification of issues and the development of positions with strict adherence to client procedures and deadlines. PCMG focuses on areas regarding revenue requirement, cost of service, rate design, cost of capital and rate of return. We provide overall analyses on various ratemaking concepts as well as a review of public utility accounting methods used by various public utilities and State Public Service Commissions. We also evaluate the reasonableness of costs and investments that are used to set rates, and measure the value of rate base, whether these costs are prudent in nature, used and useful and known and measurable in utility operations. Prior to my association with PCMG, I was employed as a Senior Consultant with the consulting firm of Snavely-King Majoros and Associates (SKM) from 2013 to 2015 in the same capacity as PCMG. Prior to SKM, I was employed by the New Jersey Board of Public Utilities (NJBPU or BPU or Board) from 1983 to my retirement in 2011. During my tenure at the NJBPU, I held various Accounting, Auditing, Rate Analyst, Supervisory and Management positions. My last position was Bureau Chief of Rates in the Agency's Water Division (Bureau Chief of Rates). I held this position for nearly 10 years. My CV is attached as Appendix A.

Q. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE SETTING PROCEEDINGS AND OTHER REGULATORY AND UTILITY MATTERS?

A. In my capacity as Bureau Chief of Rates, I was responsible for managing, assigning, directing, and overseeing the rate process regarding the administrative, financial, and managerial functions of the Rates Bureau. My primary duties were to ensure that the utilities had sufficient revenues to cover their operating expenses, while ensuring that those expenses were reasonable in nature, prudent, and known and measurable in providing service and benefits to customers, and were in accordance with Board policies, regulatory standards, and prior rate Orders. I also was responsible to ensure that the utilities had the opportunity to earn a reasonable return on their plant investments, including the ability to provide safe, adequate, and proper service at reasonable rates. During my time at the NJBPU, I was involved in hundreds of rate and rate-related proceedings that were resolved either through settlement or through fully litigated proceedings. In my capacity as a Senior Consultant, I was involved or am currently involved in rate and rate-related proceedings before the Commissions in the Commonwealths of Massachusetts and Pennsylvania, and the States of Hawaii, Maine, Maryland, New Jersey, New York, North Dakota, and Ohio. I was involved in the Generic Proceedings to Establish Parameters for the Next Generation Performance Based Rate Plans before the Alberta Utilities Commission. I have been or am currently involved in matters before the Federal Energy Regulatory Commission ("FERC") regarding transmission formula rate plans. More recently I was involved in the Generic Proceeding instituted by the NJ Board of Public Utilities (NJBPU) regarding the Tax Cuts and Jobs Act of 2017 (BPU Docket No. AX1801001) regarding the setting of the federal tax adjustments and the adjustment of rates and the impact on the flowback of excess accumulated deferred income taxes. I am currently involved in several proceedings with the NJBPU with respect to the establishment of energy efficiency and peak demand reduction programs in accordance with the NJ Clean Energy Act of 2018 (BPU Docket Nos. QO19010040, QO19060748 and QO17091004).

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Master of Business Administration ("MBA") degree with a concentration in Strategic Management from Pace University – Lubin School of Business in New York City, New York. I hold a Master of Public Administration ("MPA") degree from Kean University in Union, New Jersey. I hold a Bachelor of Science ("BS") degree in Accounting from Saint Peter's University in Jersey City, New Jersey.

Q. ON WHOSE BEHALF ARE YOUR TESTIFYING?

A. I am testifying on behalf of the Advocacy Staff of the North Dakota Public Service Commission (NDPSC).

II. PURPOSED OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to evaluate and make a revenue requirement recommendation regarding Northern States Power Company – North Dakota (NSPC or Company) gas base rate case proceeding that was filed with the North Dakota Public Service Commission (NDPSC or Commission) on September 1, 2021 in Case No. PU-21-381. My overall revenue requirement recommendations are based upon the Company's proposed test year period ending December 31, 2022. The Company has proposed an annual revenue requirement increase of $7,059,000 or 10.50% over current rate revenues. Incorporated into my testimony, I have presented findings with respect to the Company's test year rate base, revenues, operating expenses and net income at present rate revenues. I have incorporated and am relying on the recommendations of Dr. Marlon Griffing for cost of capital and return on equity, and Dr. Karl Pavlovic for cost of service and rate design that may affect my revenue requirement.

Q. HAVE YOU REVIEWED AND EXAMINED THE COMPANY'S TESTIMONY AND ACCOMPANYING EXHIBITS IN THIS PROCEEDING?

A. Yes. I have reviewed NSPC's testimony, statements and exhibits, and have also reviewed and relied on the responses to data requests propounded by Advocacy Staff and PCMG.

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared Schedules DM-1 through DM-23.

Q. PLEASE SUMMARIZE THE RATE RELIEF PROPOSED BY NSPC.

A. As previously indicated above, the Company filed an application for an increase in electric service on September 1, 2021, requesting an increase in base distribution rates in the amount of $7,059,000 or 10.50% above current rates. The revenue requirement is predicated upon a future test year ending December 31, 2022, (Exhibit BCH-1 Schedule 11) which include an overall rate of return of 7.45% and a common equity component of 10.50%. (Exhibit BCH-1 Schedule 3A). The Company has computed an average rate base balance of $124,227,000 based upon average balances of plant investments. The Company is proposing to include certain costs related to the Settlement Agreement approved by the Commission in Case No. PU-18-156 related to the expense of amortized Fargo manufactured gas plant (MGP) remediation costs of $1.25 million. The Company's last base rate case was approved in 2007 by the Commission in Case No. PU-06-525.

Q. HOW DID THE COMPANY COMPUTE ITS PROPOSED REVENUE REQUIREMENT INCREASE OF $7,059,000.

A. The Company has computed its proposed revenue requirement increase by computing the average rate base (beginning and ending test year balances) and the adding and subtracting average balances related to Cash Working Capital (CWC) materials and supplies, fuel inventory, prepayments and various non-plant assets and liabilities. The Company multiplied its proposed average rate base balance of $124,227,000 by the proposed rate of return of 7.45% to arrive at a proposed Operating Income requirement of $9,255,000. The Company then subtracted its Operating Income at present rates of $3,919,000 to arrive at an income deficiency of $5,336,000.[1] The Company then multiplied this amount by its revenue conversion factor of 1.32284 to arrive at its revenue requirement increase proposal of $7,059,000.

Q. HAVE YOU ACCEPTED THE COMPANY'S PROPOSED TEST YEAR ENDING DECEMBER 31, 2021?

A. Yes.

Q. HAS THE COMPANY UPDATED ITS PROPOSED REVENUE REQUIREMENT INCREASE SUBSEQUENT TO THE SEPTEMBER 1, 2021 FILING DATE?

A. No.

Q. WHAT HAS THE COMPANY EXPERIENCED REGARDING THE EFFECT OF THE COVID-19 PANDEMIC ON ITS PROPOSED RATE REQUEST?

A. Company witness Mr. Adam Dietenberger in response to data request 1-10 stated that the Company has experienced higher uncollectible accounts expenses in the period during the COVID-19 pandemic when compared to pre-pandemic period. The uncollectible accounts is recognized as a combination of estimating an amount of outstanding accounts receivables that will be unrecoverable and writing off uncollectible accounts not previously reflected in this provision. Mr. Dietenberger stated that as part of the Settlement Agreement in the Company's 2020 electric rate increase in Case No. PU-20-441, the Company agreed to withdraw its requested deferral of COVID-19 related costs, including bad debt and not recover such costs from its North Dakota customers. This withdrawal relates to both electric and gas businesses, for any future electric or gas rate case.

Q. WHAT HAS THE COMPANY EXPERIENCED WITH RESPECT TO ITS DAY-TO-DAY OPERATIONS?

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[1] Company Exhibit BCH-1 Schedule 7 page 1.

A. Ms. Zich stated that gas emergency response was not affected and that employees still responded to calls to ensure public and community safety was not compromised. (NDPSC 1-11). The Company was able to prioritize work to minimized contact with the public. Large capital projects were also executed accordingly.

Q. PLEASE SUMMARIZE YOUR FINDING AND RECOMMENDATIONS.

A. Based upon the use of the Company's test year period ending December 31, 2021, I have the following recommendations:[2]

1. My recommended rate base balance is $122,531,000 which is $1,695,900 lower than the Company's proposed rate base balance of $124,227,000.
2. My rate of return is based upon the recommendation of Dr. Marlon Griffing which recommends an overall return of 6.86%, which includes a common equity component of 9.43%.
3. My recommended operating revenues at present rates is $67,853,000 which is the same as the Company's operating revenues at present rates of $67,853,000.
4. My overall revenue requirement increase based upon an overall rate of return of 6.86% is $2,990,332 or 4.443%; this is $4,068,225 lower than the Company's overall revenue requirement increase of $7,059,000 or 10.48%.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized by documenting and explaining adjustments to various rate base components and net operating income components to arrive at my recommended revenue requirement decrease.

Q. ARE YOU ACCEPTING ANY OF THE COMPANY'S PROPOSED RATE BASE BALANCE AND OPERATING INCOME ADJUSMENTS?

A. Yes. I am accepting certain of the Company's Rate Base balances and certain of the Company's Operating Income adjustments. These adjustments are not identified in my testimony but are identified in my revenue requirement schedules.

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[2] Differences due to rounding

My testimony reflects the areas of disagreement from that of the Company and the affect these adjustments have on rates.

III. Cost of Capital

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS COST OF CAPITAL?

A. The Company has proposed an overall Cost of Capital of 7.35%. The breakdown of this return is based upon a long-term debt rate of 4.2189%, a short-term debt rate of 1.000% and a common equity component of 10.20%. WP C1- Cost of Capital Schedule).

Q. WHAT IS YOUR RECOMMENDED COST OF CAPITAL?

A. As per Advocacy Staff witness Dr. Griffing's recommendation, I am incorporating an overall cost of capital of 6.86% which includes a common equity component of 9.43%. This is shown on Schedule DM-2, and on Dr. Griffing's Exhibit MFG-16, Schedule 3.

REVENUE REQUIREMENT ISSUES

IV. Rate Base Issues

A. Gas Plant in Service (GPIS)

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS GAS PLANT IN SERVICE BALANCE?

A. As shown on Exhibit BCH-1 Schedule 3A the Company proposed an average plant in service balance of $222,855,000, as of December 31, 2022. The Company has developed this balance starting with total Company investments proposed in the 2021 test year period and allocating investments to the North Dakota jurisdiction. The Company calculated the investment related to the North Dakota jurisdiction by the use of a simple average of projected net plant at the beginning and end of the test year consistent with the method employed in the Company's most recent North Dakota gas rate case (Exhibit BCH-1 page 17). The Company has included costs related to the Fargo Capacity Project that was placed in service on October 13, 2021 ((Data Request 1-49). The need for this Project was explained by the Company is Ms. Zich testimony (Exhibit JHZ-1) page 20. The Company stated that there may be restoration work in the spring of 2022. The total cost of the Fargo Capacity Project was estimated at $27.5 million (Exhibit JHZ-1 page 24) and was operational during the winter of 2021-2022. The Company also included Peaking Plant Investment costs related to the Westcott LNG peaking plant, the Sibley Propane Air facility and the Maplewood Propane Air facility. (Exhibit JLZ-1 page 30). The Company stated that that these types of investments are needed to enhance reliability and maintain compliance with state and federal codes. Ms. Zich stated that the Company has made capital investments in these types of plants since the last base rate case proceeding in 2007. (Exhibit JLZ-1 page 31). Ms. Zich stated that these plant investments include significant refurbishment and replacement of the existing infrastructure in all three facilities to prepare them for continued operations for years to come and this work is occurring in the 2021-2022 timeframe. (Exhibit JLZ-1 page 32).

Q. WHAT OTHER INVESTMENTS HAS THE COMPANY INCLUDED IN ITS TEST YEAR PERIOD?

A. The Company has included costs related to the Inside Meter Move Out Program where the Company will move most of its gas meters still located inside of customer premises to outside locations and replace existing facilities with new meters, connections and regulators. (Exhibit JLZ-1 page 16). This project is required by federal code and allows the Company to more efficiently perform routine required inspections and maintenance of these meter without having to coordinate access or inconvenience to customers. (Exhibit JLZ-1 page 16). The Company is expected to replace over 550 meters outside over a five-year period beginning with 100 meters to be moved in 2022. (Exhibit JLZ-1 page 16). The average cost to move a meter to the outside is about $3,500 (Data Response 1-46). The Company is proposing to institute a Modular Replacement Program that will address the replacement of current automaking meter reading (AMR) technology, as the Company's current agreement with its meter reading provider will expire in December 2025, and the current technology will no longer be supported (Exhibit JLZ-1 page 17). The new modules will be owned by the Company and the meter reading will be performed by the Company. The program will begin in 2022 and conclude in 2025. (Exhibit JLZ-1 page 17).

Q. HOW DID THE COMPANY DEVELOP THE PLANT BALANCES FOR THE END OF THE TEST YEAR PERIOD 2022?

A. The Company stated that the 2021 ending plant balances were determined by the Company's actual net investments (Plant in Service less Accumulated Depreciation) on the books and records of the Company as of January 31, 2021. The Company budgeted projections for February through December 2021 and applied those projections to the January 31, 2021 balance to arrive at a beginning test year net plant balance. (Exhibit BCH-1 page 17). The ending net plant balances were determined by applying the data contained in the 2022 capital budget to the balance at December 31, 2021 adjusted for plant additions, retirements, depreciation, salvage and removal costs projected to occur during the test year. The result is a simple average or projected plant at the beginning and ending 2022 test year.

Q. HOW DOES THE COMPANY ALLOCATE ITS GAS PLANT IN SERVICE BALANCE FROM THAT OF THE PARENT COMPANY – XCEL ENERGY AND NORTHERN STATES POWER COMPANY – MINNESOTA (NSPM)?

A. The Company allocates its Gas Plant in Service (GPIS) balance by the use of jurisdiction allocations from NSPM (total utility) to the North Dakota jurisdiction. The jurisdiction cost of service study allocates rate base, capital structure, cost of capital, income taxes and cash working capital from NSPM to the North Dakota jurisdiction (Exhibit BCH-1 page 13). The jurisdiction cost of service schedules for the 2022 test year is shown on Company Schedule 3A (Exhibit BCH-1 page 13). The Operating Income Jurisdiction is shown on Company Exhibit BCH-1 Schedule 13 (11.2872% allocation factor) and the Rate Base Jurisdiction is shown on Company Exhibit BCH-1 Schedule 14 (11.2872% allocation factor).

Q. DO YOU HAVE ANY CHANGES OR ADJUSTMENTS TO THE COMPANY'S ALLOCATIONS FACTORS USED IN THE DEVELOPMENT OF THE COMPANY'S REVENUE REQUIREMENT?

A. No. I am accepting the Company's proposed allocation factors that were used in the development of the Company's revenue requirement proposal.

Q. DO YOU HAVE ANY ADJUSMENTS WITH RESPECT TO THE COMPANY'S GPIS BALANCE OF $222,855,000?

A. Yes. My first adjustment is related to the Company's inclusion of applying a 2% escalation factor related to the average meter installation costs of $388,500. ($3,500 per meter relocation installation costs times 111, the number of meters expected to be placed outside). I removed the 2% escalation factor or $7,617 ($388,500 / 1.02% minus $380,882 or $7,617), because I believe an escalation factor does not provide true costs of an item, as these types of costs only provide blanket increase of goods and services that may or may not reflect the costs incurred by the Company. My second adjustment is related to the Company's Fargo Capacity Plant Project. This Project included $600,000 of contingency reserves (Data Response 4-9). The Company stated that the contingency reserve is for unknowns and not quantified by individual risk items but is used to cover items not already identified. In response to Data Request 4-7 the Company stated that it does not anticipate any restoration costs in 2022. Therefore, this contingency costs should be removed from the Company's Fargo Capacity Plant Project.

Q. HAS THE COMPANY INCLUDED COSTS TO SUPPORT THE ADVANCED GRID INTELLIGENCE AND SECURITY (AGIS) INITIATIVE?

A. In Exhibit LJW-1 page 20, the Company proposed a new subaccount under FERC Account 397 for smart grid assets used to support the AGIS initiative. The Company has proposed a 10-year average service life with zero net salvage. In response to Data Request 1-62 the Company stated that it will update the costs for removing this project and calculate an update revenue requirement.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending removal of approximately $608,000 from the Company's GPIS balance shown on my Schedule DM-5. As I testified to above, inflation adjustments should not be included in the development of the revenue requirement as these types of costs do not reflect the costs that have actually been incurred by the Company. I am also removing $600,000 related to a contingency reserve related to the Fargo Capacity Plant Project as these costs are unknown and not quantified.

B. Accumulated Depreciation

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ACCUMULATED DEPRECIATION?

A. In the same manner as the Company developed its GPIS balance, the Company performed the same analysis with respect to its Accumulated Depreciation or Depreciation Reserve amount, by taking the simple average of balances at the beginning and end of test year. The Company proposed an average depreciation reserve balance of $82,973,000 as shown on Company Exhibit BCH-1 Schedule 3A.

Q. DO YOU HAVE ANY ADJUSMENTS WITH THE WAY THE COMPANY DEVELOPED ITS ACCUMULATED DEPRECIATION BALANCE?

A. No. I am accepting the Company's methodology as to the development of the Company's Accumulated Depreciation.

Q. WHAT SPECIFIC ADJUSTMENTS DO YOU HAVE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S GPIS BALANCE?

A. As I removed approximately $608,000 from the Company's UPIS additions related to the meter installation project and the contingency costs related to the Fargo Capacity Plant Project, I am removing the associated Accumulated Depreciation of $16,078 (computations addressed under Depreciation Expense in Section K). My adjustment is shown on my Schedule DM-6.

C. Accumulated Deferred Income Taxes (ADIT)

Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS ACCUMULATED DEFERRED INCOME TAXES?

A. The Company has proposed an ADIT balance of $19,782,000 as shown on Exhibit BCH-1 Revised Schedule 15. The Company used an average projected ADIT balance of projected beginning and ending 2022 test year ADIT balances and incorporates IRS tax regulations. (Exhibit BCH-1 page 19). With respect to the TCJA of 2017, the Commission adopted a Settlement in Case No.PU-18-156 that required the Company to amortize its excess plant – related ADIT using the Average Rate Assumption Method (ARAM) and amortize unprotected, excess non-plant related ADIT over a three-year period. Consistent with this requirement, the Company amortized the excess plant related ADIT using ARAM and the excess non-plant related ADIT was amortized over a three-year period ending in 2020, therefore no impact remains in the 2022 test year. (Exhibit BCH-1 page 20).

Q. DO YOU HAVE ANY ADJUSTMENTS REGARDING THE COMPANY'S METHODOLOGY ON THE DEVELOPMENT OF ITS ADIT?

A. No. I am accepting the Company's methodology as to the development of the Company's ADIT.

Q. WHAT SPECIFIC ADJUSTMENTS DO YOU HAVE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S GPIS BALANCE?

A. My adjustments reflect the flow through of my adjustments related to the Fargo Capacity Plant Project and the adjustment related to the inflation adjustment for the meter installation project and applying a 21% income tax rate to arrive at a balance of $3,376. My adjustment is shown on my Schedule DM-7.

D. Cash Working Capital (CWC)

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO CASH WORKING CAPITAL (CWC)?

A. The Company has proposed a CWC balance of $648,000 as shown on Exhibit BCH-1 Revised Schedule 3A. The Company has included certain investments, various non-plant assets and liabilities. (Exhibit BCH-1 page 29). For certain components, the Company has used thirteen-month average balances projected during the test year. For other components, the Company has used a simple average of beginning and ending test year balances. The Company has calculated its CWC by applying the results of a comprehensive lead/lag study to the projected test year revenues and expenses. (Exhibit BCH-1 page 30-31).

Q. DO YOU HAVE ANY ADJUSTMENTS IN THE WAY THE COMPANY HAS COMPUTED ITS CWC BALANCE?

A. No. I am accepting the Company's methodology but have adjustments related to my recommended adjustment to the Company's proposed revenues and expenses.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. In response to Data Response 4-3, the Company stated that it inadvertently included in the All Other Operating Expenses fuel expenses. The Company stated that correcting this placement in the CWC calculation reduces the Company's revenue requirement by $122,000. The Company calculated an CWC of ($673,000) and has stated that it will update its filing in its rebuttal testimony. Based upon this response, I have adjusted my CWC accordingly and based upon my adjustments to the Company's Rate Base components, the Operating Income and the Operating Expenses, I have calculated a CWC balance of ($438,738). This is shown on Schedule DM-8.

E. Other Rate Base Items

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO NON-PLANT ASSETS AND LIABILITIES?

A. The Company proposed other Rate Base Item of $3,292,000 as shown on Exhibit BCH-1 Schedule 3A ($3,940,000 less Cash Working Capital of $648,000).

Q. DO YOU HAVE ANY ADJUSTMENTS RELATED TO THE COMPANY'S PROPOSED OTHER RATE BASE ITEMS?

A. Yes. I have one adjustment related to the Company's Regulatory Amortization for its proposed Income Tax Tracker (WP A15).

(1) <u>Gas Income Tax Tracker</u> – ND $27,951 (Company shows $22,547).

Q. WHAT DOES THIS BALANCE REPRESENT?

A. (1) The <u>Gas Income Tax Tracker</u> – Mr. Halama stated that the Company has concluded tax audits with the IRS and the Minnesota Department of Revenue for tax years ending 2010 through 2016. As a result of the audits the Company paid tax and interest on the disputed amounts. The Company has proposed to collect this amount over three years consistent with rate case expenses. (Exhibit BCH-1 page 39).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S GAS INCOME TAX TRACKER?

A. My adjustment to the Company Gas Income Tax Tracker – ND is to remove this balance of approximately $23,000. The Company has proposed to earn a return on the unamortized balance and also recover this through an amortization expense of $9,317 over a three-year period. The Company should not be able to earn a return on taxes and interest (carrying costs) and also recover the unamortized balance through the cost of service (amortization expense). Typically these types of costs should only be recovered through an amortization expense. There is no reason why the Company should earn a return and carrying costs that are related to the payment of taxes and interest liabilities (penalties). These audits were for the period (tax years) ending 2010-2016. My adjustment removes $23,000 from the Company's Regulatory Amortization balance. This adjustment is shown on Schedule DM-3.

V. Operating Income Issues

A. Operating Revenues

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS OPERATING REVENUES AT PRESENT RATES?

A. The Company has proposed Operating Revenues at Present Rates of $67,853,000 as shown on Exhibit BCH-1 Schedule 3A. The Gas Retail Revenues are comprised of $67,303,000 plus Other Operating Revenues of $550,000.

Q. HAS THE COMPANY EXPERIENCED ANY IMPACT RELATED TO THE COVID-19 PANDEMIC?

A. Company witness Marks stated that the COVID-19 Pandemic negatively impacted the North Dakota economy in 2020. Non-farm employment declined 12.3 percent. While 2020 experienced the greatest economic impact from the pandemic, the effects will linger throughout 2021 and into the 2022 test year. (Exhibit JEM-1 page 4). Mr. Marks stated that customer count increased by 1.9 percent in 2020 and sales increased by 0.6 percent with Residential sales increasing 3.0 percent and Commercial and Industrial and Interruptible sales decreasing 0.3 percent. (Exhibit JEM-1 page 5). Mr. Mark's expected a reduction in Residential Sales in 2021 relative to the pandemic – inflation levels seen in 2020, and a modest increase in 2022. (Exhibit JEM-1 page 6).

Q. WHAT WEATHER NORMALIZATION PERIOD HAS THE COMPANY USED TO DEVELOP ITS SALES REVENUES?

A. The Company has utilized a 15-year weather normalization period (Exhibit JEM-1 page 9). Mr. Marks stated that after normalizing for weather, the Company's total gas sales have increased an average 2.4 percent per year during the period 2007-2022, with declines in only two years (Exhibit JEM-1 page 9).

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S OPERATING REVENUES AT PRESENT RATES?

A. No, I am accepting the Company's Present Rate Revenues.

B. Operating and Maintenance Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS OPERATING AND MAINTENANCE EXPENSE?

A. As shown on Exhibit BCH-1 Schedule 3A, the Company proposed a total Operating and Maintenance Expense (O&M) balance for the 2022 test year of $54,365,000. This balance is composed of various accounts related to Purchased Gas, Gas Production and Storage, Gas Transmission, Distribution, Customer Accounting/Customer Service, Sale/Economic Development and Administrative and General. This balance includes the Company specific adjustments in each of the accounts listed above, and as shown on Exhibit BCH-1 Revised Schedule 6.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S OVERALL OPERATING AND MAINTENANCE EXPENSES?

A. I have adjustments to certain of the Company's overall O&M Expense balance that do not include specific adjustments the Company has made and proposed as shown on Exhibit BCH-1 Revised Schedule 4. My overall adjustments to the Company's certain O&M Expense incorporate the use of a three-year normalization adjustment minus any labor adjustments.

Q. WHY ARE YOU USING A NORMALIZATION ADJUSTMENT TO CERTAIN OF THE COMPANY'S OVERALL O&M EXPENSES?

A. A review of the Company's O&M Expenses shows that certain of the Company's balances for the periods 2019-2021 (Data Request 01-034 Attachment A) fluctuate and vary from year to year. In other accounts, the balances during the same period appear to be abnormal and irregular from what the Company is proposing to utilize and set in the test year 2022 period. In other areas there are negative balances or no prior costs accounted for. Data Request 01-034 reflects these fluctuations and variabilities from year to year. A further inquiry of certain expense breakdown categories were asked for and received in Data Request 4-12, 4,13 and 4-14. The use of a three-year normalization period smooths out fluctuations in setting rates going forward. Prior costs can also show and provide a trend of expenses that were incurred by the Company to determine the reasonableness of the adjustments in costs going forward.

It is appropriate to normalize these types of costs to set rates in this proceeding. Finally, certain costs are usually out of the Company's control in that they relate to outside vendors or third-party providers.

Q. DID YOU ASK THE COMPANY FOR AN EXPLANATION WHY CERTAIN COSTS HAVE FLUCTUATED FROM YEAR TO YEAR?

A. Yes. In response to Data Request 04-012, 04-013 and 04-014, I asked the Company for a description regarding certain fluctuations. These will be addressed under Section 2, 4 and 5.

Q. UTILIZING YOUR THREE-YEAR NORMALIZATION APPROACH WHAT IS YOUR OVERALL ADJUSTMENT TO THE COMPANY'S O&M EXPENSE?

A. As more fully reflected on Schedule DM-10, my three-year normalization adjustments (which does not include labor adjustments) is an overall decrease of $1,234,735, or an overall O&M Expense balance of $49,037,537, from the Company's proposed balance of $50,272,272, not including the specific adjustments as outlined in my testimony below under each Expense category, and without labor costs.

Q. PLEASE ADDRESS YOUR AVERAGING ADJUSMENTS UNDER EACH EXPENSE CATEGORY.

A. My averaging adjustment are as follows:

1. Gas Production & Storage

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S GAS PRODUCTION & STORAGE EXPENSE?

A. In response to Data Request 4-12, I asked the Company for an explanation of the variability related to its Gas Production and Storage balance from $2.1 million in 2019 to $289,000 in 2022. The Company responded by stating that the difference is related to the Company's $1.25 million of MGP amortization which was not included in the 2021-2022 rate case data in the direct testimony of Mr. Halama. The actual 2019 Gas Production and Storage Expense also included $242,000 in MGP clean-up costs the Company agreed to expense in the event it earned more than the authorized ROE during the remediation phase of the project. Given this information I am accepting the Company's Gas Production and Storage balance of $289,000.

2. Transmission Expense

Q. WHAT IS INCLUDED IN THE COMPANY'S GAS TRANSMISSION EXPENSE?

A. As shown on Data Response 01-034 Attachment A the Company proposed a balance of $304,359 for the test year ending 2022.

Q. WHAT HAS BEEN THE AVERAGE TRANSMISSION EXPENSE BALANCE IN PRIOR YEARS?

A. As shown in response to 01-034 Attachment A, the Company has recorded Gas Transmission costs of $246,098 in 2010, $239,491 in 2020 and $294,982 in 2021.

Q. WHAT IS YOUR ADJUSTMENT?

A. I am recommending averaging out or normalizing these costs over a three-year period from 2019-2021. This reduces the balance by $44,169. This is shown on my Schedule DM-10.

3. Gas Distribution

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS GAS DISTRIBUTION EXPENSE?

A. As shown in Data Response 01-034 Attachment A, the Company proposed Gas Distribution Expense of $3,278,109 for the test year period ending 2022. This balance does not include Labor Costs.

Q. WHAT HAS BEEN THE AVERAGE GAS DISTRIBUTION EXPENSE IN PRIOR YEARS?

A. The Company recorded $1,890,632 in 2019, $1,965,662 in 2020 and $3,274,274 in 2021.

Q. WHAT HAS THE COMPANY STATED WAS THE CAUSE FOR THE VARIABILITY?

A. In response to 4-13, the Company stated that the variability related to MNND Border costs, GCUstomer costs and GDirectND costs were due to volatility in actual expenses, including weather and weather related incidents, damage prevention locate volumes, contractor prices and compliance requirements. The Company stated that forecasted O&M data in the years 2021 and 2022 reflect estimates related to proposed work in the forecasted year(s) and developed at a high level and therefore does not provide the same level of cost differentiation by allocated methods. The Company stated that comparisons between actual and forecasted O&M at a refined level such as labor/non-labor or jurisdictional allocators may show deviations that do not exist when the O&M Expense is compared in total.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am recommending normalizing these costs by averaging these out for the periods (2019-2021). These types of costs that the Company has described above, do vary from year to year and are caused by many difference factors including weather, damage prevention locate volumes, contractor pricing and compliance requirements. Smoothing out these fluctuations provide for an overall level of recurring expenses and cost recoveries going forward. My normalization adjustment is a reduction of $901,252 and is shown on my Schedule DM-15, broken down by MNND Border, G Customers and G Direct ND categories.

4. Customer Accounting

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS CUSTOMER ACCOUNTING EXPENSE?

A. The Company has proposed a Customer Accounting balance for the test year 2022 of $1,217,726 shown in Data Response 01-034 Attachment A. These costs include Bad Debts, Customer related expenses and Direct charges to North

Dakota. Total costs assigned to this category including Labor Costs were $1,612,721 as shown in Data Request 01-34 Attachment A.

Q. WHAT HAS BEEN THE COMPANY'S EXPERIENCE RELATED TO BAD DEBTS?

A. As explained in Data Response 01-10, the Company has experienced higher uncollectible accounts expense in the period during the COVID-19 pandemic when compared to pre-pandemic period. The Company has recorded incremental provisions amounts monthly to recognize the additional risk of accounts becoming uncollectible due to the impact of the COVID-19 pandemic. In response to Data Request 4-14, the Company stated that these types of costs are directly assigned to jurisdiction whenever possible, and costs are directly assigned to the North Dakota jurisdiction using the GDirectND jurisdiction allocator. The Company broke down these costs further to show the costs related to Labor, Meter Reading, Records and Collections, Uncollectible Bad Debt and Miscellaneous. (04-14 Attachment A).

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S CUSTOMER ACCOUNTING EXPENSE?

A. I am normalizing the Company's Bad Debt Expense over a three-year period (2019-2021). This increases the Company's costs by $4,204. My next adjustment is related to costs related to Supervision, Meter Reading, Record and Collections and Miscellaneous costs. Normalizing these cost by averaging them out using a three-year (2019-2021) average, results in a reduction of $191,159. My final adjustment is related to Direct Costs assigned to the North Dakota jurisdiction related to Meter Reading Expenses and Miscellaneous Costs. Normalizing these costs by averaging them out using a three-year (2019-2021) average results in a reduction of $114,312. My total Customer Accounting Expense adjustment is an overall decrease from $1,217,726 to $916,459 or a reduction of $301,267.

5. Customer Service & Information Expense

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S CUSTOMER SERVICE AND INFORMATION EXPENSE?

A. I used a simple average of these costs for the periods 2019-2021. The Company has proposed a balance of $140,217 for the test year 2022. My three-year average adjusts the balance to an increase of $11,853 and a proposed 2022 balance of $152,070. This balance is shown on Schedule DM-10.

6. Sales, Economic Development and Other Expenses

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S SALES, ECONOMIC DEVELOPMENT AND OTHER EXPENSES?

A. While I did not average out the Company's balance of $8,872, I do have an adjustment related to the Company's Economic Development Donations of $7,382. This adjustment will be addressed under Section I of my testimony below. This balance is shown on Schedule DM-10.

7. Administrative & General Expenses

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S ADMINISTRATIVE AND GENERAL EXPENSES?

A. While I did not average out the Company's balance of $1,099,071, I do have adjustments related to several of the Company Precedential and Ratemaking Adjustments, which will be addressed under Section J of my testimony below. My balance is shown on my Schedule DM-10.

C. Purchased Gas Expenses

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S PROPOSED PURCHASED GAS EXPENSES?

A. In reviewing the Company's filing and related data responses to Purchased Gas Expenses, I am accepting the Company's balance $43,934,000 as shown on Company Exhibit BCH-1 Schedule 3A.

D. Gas Production & Storage Expenses

Q. WHAT SPECIFIC ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S REMAINING PROPOSED GAS PRODUCTION & STORAGE EXPENSES?

A. In reviewing the Company's filing and related data responses to Gas Production & Storage Expenses, I am accepting the Company's remaining Gas Production & Storage Expenses.

E. Gas Transmission Expenses

Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH RESPECT TO ITS TRANSMISSION EXPENSES?

A. The Company has initiated a Damage Prevention Program (DPP) that assigns costs to the Company's Transmission, Distribution, Customer Service and A&G expense categories (Data Response 1-53 Attachment A). The Company stated that the DPP helps excavators and customers locate underground gas infrastructure to avoid accidental damage and safety incidents. (Exhibit JLZ-1 testimony page 37). The Company contracts with and relies on internal labor and contractors to implement the DPP, of which the primary purpose is to reduce damage to Company – owned buried facilities caused by excavation. This requirement is further supplemented by state law in North Dakota. (Exhibit JLZ-1 testimony page 37). This program is designed to ensure compliance with state and federal regulations and NSP relies heavily on contractors to perform this work. The Company has stated that damage prevention costs have increased by $400,000 between 2019 and 2020 actuals and are further forecasted to increase by $100,000 between 2020 and 2021, due to the increases attributable to both an increase in the volume of underground locate requests and a higher contract cost per locate due to contractor cost increases. (JLZ-1 testimony page 37-38).

Q. WHAT HAS THE COMPANY PROVIDED TO SHOW THESE COSTS RELATED TO THE DPP?

A. The Company provided breakdown these costs by account number for the periods 2019-2020 actuals, forecasted 221 and FTY 2022. (Data Response 1-53 Attachment A).

Q. WHAT DOES THIS DATA RESPONSE SHOW OR INDICATE?

A. According to the data response 1-53 Attachment A, the majority of the dollar amount related to the DPP were recorded in the Gas Distribution category, particularly in Account No. 874 where the initial cost of this program was $577,153 and increases to $1,131,448 through the FTY 2022. The costs accounted for under the Gas Transmission Expense category (Accounts 851 and 856) were minimal and no projected expenses were proposed in FTY 2022.

Q. WHAT ARE YOUR ADJUSTMENTS RELATED TO THE DPP FOR THE COMPANY'S GAS TRANSMISSION EXPENSE?

A. I am not recommending any adjustment to the Company's Gas Transmission Expense related to the DPP as the Company did not project any costs in the Forecasted 2021 and the FTY 2022.

F. Gas Distribution Expenses

Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH RESPECT TO ITS DISTRIBUTION EXPENSE?

A. As previously discussed above under the Gas Transmission Expense, the Company has proposed costs related to its DPP in the amount of $1,131,448 (Data Response 1-53 Attachment A). This expenses is solely related to Distribution Expense – Mains and Services under Account 874.

Q. WHAT ARE YOUR ADJUSTMENTS RELATED TO THE COMPANY'S DPP?

A. I am normalizing this expense by averaging these costs over three years (2019-2021). The Company has provided actual cost for the DPP (2019-2020) and forecasted costs for 2021 and in 2022. Given that the Company's 2021 cost increase was forecasted due to vendor contracts expiring, the labor market was tight, and insurance premiums increased, and that inaccurate locates performed by Company employees increased, costs should remain consistent and in line with prior costs. The Company is expected to utilize outside contractors as any damages that will occur will be covered by the vendors and not the Company or its employees. (JLZ- 1 testimony page 37). Normalizing these costs over a three year average reduces the balance by $245,950. This is shown on my Schedule DM-15.

G. Customer Accounting Expenses

Q. WHAT ADJUSTMENTS HAS THE COMPANY PROPOSED WITH RESPECT TO ITS CUSTOMER ACCOUNTING EXPENSES?

A. The Company did not propose any specific adjustment to its Customer Accounting Expenses. As discussed previously, the only adjustments that I have are related to normalizing certain costs using a three year average.

H. Customer Service & Information Expenses

Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH RESPECT TO ITS CUSTOMER SERVICE & INFORMATION EXPENSES?

A. The Company removed $40,000 related to its Advertising Expense (WP-A1 and Company Exhibit BCH-1 Schedule 4). The Advertising Expense was related to Conservation DSM costs.

Q. WHAT WERE THE COMPANY'S TOTAL ADVERTISING COSTS PROPOSED IN 2022?

A. As shown on Workpaper A1-Advertising, the Company recorded total Advertising Costs of $100,071. The remaining Advertising Costs included were related to Customer Assistance, Informational and Instructional expense, Economic Development and A&G General Advertising.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S CUSTOMER SERVICE & INFORMATION EXPENSE – ADVERTISING?

A. I am removing $1,471 of Advertising Expense that is related to Economic Development. Since I am recommending removing Economic Development Donations under the Company's Sales, Economic Development & Other Expenses, I am recommending that these costs under Advertising should also be removed. My arguments for removing these costs are as outlined below under Section I. My recommendation is shown on my Schedule DM-17.

I. Sales, Economic Development & Other Expenses

Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH RESPECT TO SALES, ECONOMIC DEVELOPMENT AND OTHER EXPENSES?

A. As shown on Exhibit BCH-1 Schedule 4 and Schedule 6, the Company proposed an adjustment related to Economic Donations in the amount of $7,382. A breakdown of these balance is shown on Workpaper A11. (portion allocation to ND Gas Jurisdiction).

Q. WHAT IS INCLUDED IN THE COMPANY'S $7,382 ECONOMIC DEVELOPMENT DONATIONS?

A. Company Witness Mr. Halama (Exhibit BCH-1 page 37) stated that the Company makes contributions to a number of regional and local economic development organizations positioned to combine resources for the purposes of maintaining and improving the long-term economic health of communities in its service territory or retaining employment opportunities and expanding the state and local tax base. In response to NDPSC 1-41, these costs provide financial and collaborative support to local, regional and state organizations. It is an estimate. These costs are used to assist in the strategic advancement of the communities served by the Company for job creation, GDP growth and the overall social well-being for individuals and businesses. Because no 2022 contributions had been made at the time of filing, there is no further breakdown or description of these donations.

Q. WHAT IS YOUR POSITION ON ECONOMIC DEVELOPMENT DONATIONS?

A. I do not believe that ratepayers should pay for these types of costs in rates. These expense items are akin to charitable contributions. The Company is a utility company providing gas utility service to certain parts of North Dakota. The Company should not be expensing costs related to non-utility type services, nor be in a position to support regional and local economic development. These type of initiatives should be provided at the State and Local or even at the Federal level. Additionally, ratepayers do not have a say in what type of donations they are paying for, or whether ratepayers receive any benefit for these contributions. These types of costs should not be included in the revenue requirement proposed by the Company. Given that no 2022 contributions had been made at the time of filing, there is no way to determine exactly how much money was expended in the FTY 2022. The Company should pay for these costs, below the line, and receive the tax benefits through the corporate entity.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending removal of the $7,382 of Economic Development Donations from the Company's Sales, Economic Development and Other Expenses balance. This is shown on Schedule DM-18.

J. Administrative & General Expenses

Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH RESPECT TO ITS ADMINISTRATIVE AND GENERAL EXPENSES?

A. As shown on Exhibit BCH-1 Schedule 4 and 6, the Company proposed an Unadjusted Balance of $2,638,502, Precedential Adjustments of ($145,568) and Ratemaking Adjustments of $14,483, computing to Adjusted Balance of $2,507,656. These adjustments reflect Precedential Adjustments which the Company has not changed from the Commission's Order in the Company's previous completed electric rate cases (Exhibit BCH-1 page 34). The Company has also reflected Ratemaking Adjustments that relate to specific adjustments in this instant proceeding. I will address each of these Precedential and Ratemaking Adjustments below.

Q. WHAT SPECIFIC PRECEDENTIAL ADJUSTMENTS HAS THE COMPANY PROPOSED IN THIS PROCEEDING?

A. The Company has proposed the following Precedential Adjustments:

<u>**Precedential Adjustments**</u>

Advertising -	($ 28,856)	WP A1
Customer Deposits -	$ 676	WP A3
Incentive Pay	($ 17,013)	WP A4
Incentive Pay LTI	($ 97,348)	WP A5
SERP -	($ 3,027)	WP A6

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S PRECEDENTIAL ADJUSTMENTS?

A. I have reviewed each of the Company's Precedential Adjustments, and I am accepting the Company's adjustments totaling ($145,568). This is shown on my Schedule DM-19.

Q. WHAT ARE THE OTHER SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED IN THIS PROCEEDING?

A. The Company has proposed five Ratemaking Adjustments:

<u>**Ratemaking Adjustments**</u>

a.	Aviation	($22,003)	WP A7
b.	Dues - Chamber of Commerce	$ 2,221	WP A10
c.	Economic Development Donations	$6,226	WP A12
d.	Incentive Pay – Environ. LTI	$17,060	WP A13
e.	Incentive Pay – Time Based LTI	$10,979	WP A14

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S RATEMAKING ADJUSTMENTS ABOVE?

A. I adjusted the Company's Ratemaking Adjustments per above and which is reflected on Schedule DM-19.

a. Chamber of Commerce Dues – ($2,221)
b. Economic Development Donations – ($6,226)
c. Incentive Pay Environmental LTI –
d. Incentive Pay Time Based LTI -

a. Dues - Chambers of Commerce

Q. WHAT HAS THE COMPANY INCLUDED IN ITS CHAMBERS OF COMMERCE?

A. The Company has included $2,221 of Chamber of Commerce Dues in revenue requirement request. (Workpaper A10 and Company Exhibit BCH-1 Schedule 4). Company witness Mr. Halama stated that these costs provide an essential link between the Company and the communities it serves and facilitate improved utility service (BCH-1 testimony page 36). Mr. Halama stated that because membership in these organizations provide benefits to all utility customers, recovery of membership dues paid to Chambers of Commerce is appropriate. (Exhibit BCH-1 page 36).

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am recommending no recovery because this type of cost does not benefit North Dakota ratepayers. This cost mainly serves to advance the policy positions before State and Governmental agencies and to communicate its corporate citizenship initiatives. Ratepayers should not be required to pay for such costs which provide no benefit to utility service. I am recommending removal the Company's Chamber of Commerce costs of $2,221. Further, in response to Data Request 1-40, The Company has indicated that no 2022 contributions have been made and no breakdown can be provided.

b. Economic Development Donations

Q. WHAT HAS THE COMPANY INCLUDED IN ITS FOUNDATION AND OTHER DONATIONS?

A. The Company has included $6,226 of costs related to Economic Donations. Company witness Mr. Halama stated that the Company makes contributions to a number of regional and local economic development organizations positioned to combine resources for the purpose of maintaining and improving the long-term health of communities in its service territory or retaining employment opportunities and expanding the state and local tax base. (Exhibit BCH-1 testimony page 37). .

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending that the $6,226 costs related to Economic Development Donations be removed from the Company's costs of service. In response to Data Request 1-42, the Company has not contribution any dollars in 2022 and there is not breakdown of these costs. These costs are similar to Charitable Contributions, and in general, should be removed from the Company's cost of service because ratepayers do not have any say of what type of contributions they are paying for. These types of payments do not benefit ratepayers, and as I stated previously in my testimony, and only benefits the Company as being good corporate citizens. These costs should be funded below the line by the shareholders of the Company and receive a tax benefit through the corporate entity. The Company does not have the right to make others pay for charitable contributions, especially those costs that do not provide specific benefits to its ratepayers. My recommendation is shown on my Schedule DM-19.

<u>c. Incentive Pay – Environmental LTI</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO INCENTIVE PAY – ENVIRONMENTAL LTI?

A. According to Company witness Mr. Chamberlain, the Company is seeking to adjust recovery in rates for the Long-Term Incentive program (LTI) in the amount of $17,060 for its Environmental LTI. (Exhibit GPC-1 testimony page 22) (Exhibit BCH-1 Schedule 4) (WP A13). The LTI is available to the Company's senior and executive level employees, of which less than five percent of exempt and non-bargaining employees are eligible for LTI. The LTI is intended to incentivize these senior employees to effectively manage the Company towards its overall goals and in the best interest of customers and shareholders. The LTI is geared toward employees who have a higher influence in the Company's direction and strategy. (Exhibit GPC-1 testimony page 22). The LTI program helps retain key employees and is necessary for Xcel Energy to remain competitive in the labor market. (Exhibit GPC-1 testimony page 22). The Environment portion is tied into achieving the Company's environmental goals which will result in efficiencies, allow for a lower cost of capital and remove fuel costs in addition to environmental benefits and other benefits. (Exhibit GPC-1 testimony page 23).

Q. DID THE COMPANY PROVIDE ANY INFORMATION WITH RESPECT TO GOAL ACHIEVEMENT AND SCORECARD RESULTS?

A. In response to Data Request 1-14, the Company stated that 2021 Corporate Scorecard final results have not yet been calculated and approved. The Company stated that 2021 Scorecard will determine the payout anticipated on March 9, 2022. (Data Response 1-15). The Company stated that the LTI plans requires a three-year service commitment with the Company which typically occurs in February following the third year of vesting. (Data Response 1-13 and 14).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. Given that the Company's Corporate Scorecard final results will not occur until March 2022, the Company's proposed Annual Incentive related to Environmental LTI is unknown and not measurable. Also, these Annual Incentive costs are geared toward senior and executive level employees from preventing them from leaving the Company, and to maintain and retain these employees as hiring these types of employees are expensive and time-consuming to fill. (Exhibit GPC-1 testimony page 22). In response to Data Request 1-16, the Company provide a schedule of senior and executive employees who left the Company. In the past three years (2019-2021) the Company experienced 2 non-retirement leaves and zero retirement leaves for the NSPM total Company. The Company does not track reasons for terminating employment beyond retirement and these are allocated across each of the associated jurisdictions. Therefore, I am recommending that the Company's Environmental LTI of $17,060 be removed from the Company's A&G expenses. (add more language, discuss with Advocacy Staff). My recommendation is shown on my Schedule DM-19.

<u>d. Incentive Pay – Time Based LTI</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS TIME BASE LTI?

A. The Company has proposed to recover $10,979 based upon an LTI which is a program tied to the length of key employee's service with the Company. The Company stated that it benefits from its ability to retain institutional knowledge and capabilities of key employees. (Exhibit GPC-1 testimony page 23) (Exhibit BCH-1 Schedule 4) (Workpaper A14).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. As more fully discussed above, I am also recommending that the Company's $10,979 related to Time Based LTI be removed from the Company's A&G expenses. These costs area not known and measurable as the Company has not finalized its Scorecard which would determine the payout. This will occur on March 9, 2022. (Data Response 1-15). **(add more language as needed, discuss with Advocacy Staff).** My recommendation is shown on my Schedule DM-19.

K. Labor Adjustments

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO LABOR EXPENSE?

A. As shown on Data Response to 01-034 Attachment A, the Company proposed total Labor Expense of $4,093,208 for all employee categories. The Company allocated these labor costs by direct assignment or allocated to the North Dakota Gas Utility operations. (Exhibit BCH-1 testimony page 25 and 29). The cost allocation and assignment principles are consistent with the Company's recent North Dakota electric rate case filed on November 6, 2020 in Case No. PU-20-441. (Exhibit BCH-1 testimony page 29).

Q. DID THE COMPANY PROVIDE A SCHEDULE OF EMPLOYEES EXPECTED TO BE HIRED BY NSPC-GAS COMPANY IN THE PROJECTED YEAR 2022?

A. Yes. In response to Data Request 1-19, the Company provided a schedule of employees as potential candidates. Positions will be filled as soon as possible, but the specific dates are not known. The Company stated that the position list will also continue to change throughout the year. The Company stated that it cannot determine the anticipated hire data for the specific opening.

Q. HAS THE COMPANY PERFORMED A VACANCY RATE ANALYSIS FOR THE NSPC- GAS UTILITY OPERATIONS?

A. No. The Company stated in response to Data Request 1-18, that it works with leaders in certain areas regarding attrition and the need for posting open positions, the Company does not conduct a formal vacancy rate analysis.

Q. WHAT APPROACH HAVE YOU DETERMINED TO ADJUST LABOR COSTS?

A. I am recommending an adjustment of labor for all O&M labor by functional group by the use of a vacancy rate analysis. I relied on the Company's response to NDPSC 01-034 Attachment which shows the labor costs allocated to the North Dakota's Gas jurisdiction, by Operating Expense account. I relied on the response to Data Requests 1-20 that shows the employee headcount of NSPM-Minnesota for the years 2019-2022. The response to 1-6 which asked for the allocation of employees related to the North Dakota jurisdiction – Gas Utility for the years 2019 – 2022, refers me to Mr. Halama's Exhibit BCH-1 Schedule 12. Finally I reviewed the Company's response to Data Request 1-17 which reflects the level of employees who have left the Company (Non-Retirement and Retirement). Given that the Company allocates its labor costs by jurisdictional allocation, and these can vary from year to year, it is appropriate to adjust these labor costs prospectively. Labor costs can vary from year to year in each of NSPM's service territories and depending on the circumstances and the need to allocate labor, costs can vary.

Q. HOW DID YOU ADJUSTMENT TO THE COMPANY'S TOTAL LABOR COSTS?

A. I began with the number of employees of NSPM – Minnesota (Data Response 1-20) which shows the number of employees from 2019 through 2022. I then allocated these balances by the allocation factor of 11.2872% as shown on Exhibit BCH-1 Schedule 12 to reflect the number of employees allocated to the North Dakota – Gas Operations:

	NSPM	Factor	Allocated to NSPM-ND-Gas
2019	3,186	11.2872%	359
2020	3,118	11.2872%	352

2021	3,285	11.2872%	371
2022	3,266	11.2872%	369

I then reviewed the response to Data Request 1-17 which shows the number of NSPM total employees who have left the Company. I divided the number of employees allocated to the North Dakota – Gas Operations in each year by the number of employees who have left the Company to arrive at a vacancy rate as follows:

				Ratio to Total	3 Yr. Avg
2019	120	11.2872%	14	3.899%	
2020	112	11.2872%	13	3.693%	
2021	171	11.2872%	19	5.121%	4.2366%

Q. WHAT WERE YOUR NEXT STEPS?

A. I then took the three year average of 4.2366% and multiplied that ratio by the total Labor costs allocated to the North Dakota – Gas Operations of $4,093,208 shown on Data Request 1-34 Attachment A to arrive at a vacancy adjustment of $173,412. This is shown on my Schedule DM-4.

L. Depreciation Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO DEPRECIATION EXPENSE?

A. The Company proposed an Unadjusted Depreciation Expense balance of $6,845,000 as shown on Exhibit BCH-1 Schedule 6. The Company proposed an adjustment of ($31,918) related to Remaining Life for Gas Manufactured Production Plant and Gas Other Storage plant. (WP A8) The Company proposed an adjustment of $78,123 related to a Depreciation Study for its plant balances

(WP A9). According to Ms. Wold in her testimony Exhibit LJW-1 page 2, these adjustments reduced the Depreciation Expense at the North Dakota jurisdiction by $19,000.

Q. WHAT ADJUSTMENTS DID THE COMPANY INCORPORATE THAT RESULTED IN A REDUCTION OF DEPRECIATION EXPENSE?

A. According to Ms. Wold the increase in service lives and changes in net salvage rates decreased the Gas Production and Storage Depreciation by about 32,000 (LJW-1 testimony page 2). Gas Depreciation expenses were decreased by $49,000 in the allocation portion of Common Utility assets and partially offset by $62,000 for the North Dakota jurisdiction that increased Depreciation expense for Gas Transmission, Distribution and General assets. (LJW-1 testimony page 3, and Table 1 page 3 and Table 2 page 11).

Q. WHAT ADJUSTMENT DO YOU HAVE WITH RESPECT TO THE COMPANY'S DEPRECIATION EXPENSE?

A. While I do not have any adjustments related to the Company's Depreciation Study and Remaining Life Adjustments, I do have an adjustment related to the removal of certain plant additions. Since I removed costs related to certain inflation increases and contingency factors that I discussed under my Gas Plant In Service Testimony, I am removing the associated Depreciation Expense. I utilized the Company's composite rate of Depreciation which was computed by the information responded to in Data Request 1-61 (Exhibit LJW-1 Schedule 9), which calculates out to 2.646%. I then multiplied the adjustment to the Gas Plant Additions of $607,617 times the Composite Depreciation rate of 2.646% to arrive at an adjustment of $16,078. This is shown on my Schedule DM-20.

M. Amortization Expense

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS AMORTIZATION EXPENSE?

A. The Company has proposed a total Amortization Expense of $439,979 (Exhibit BCH-1 Schedule 6). The breakdown is as follows:

a).	Income Tax Tracker	$ 9,317
b).	NOL ADIT ARAM	$ 22,547
c).	Rate Case Expenses	$408,115
	Total	**$439,979**

a). Income Tax Tracker - $9,317

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS INCOME TAX TRACKER OF $9,317?

A. The Company stated that it has concluded tax audits with the IRS and the Minnesota Department of Revenue for tax years 2010-2016, and as a result of the audits, the Company paid tax and interest on the disputed amounts. The Company is proposing to recover these costs over a three year period consistent with rate case expenses (Exhibit BCH-1 testimony page 39). ($27,951/3). (WP A15).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's Income Tax Tracker proposal, and the costs allocated to the North Dakota jurisdiction of $27,951. I am recommending an amortization period of 5 years instead of 3 years. This will allow the Company to recover its Income Tax Tracker costs between normalized rate case proceedings. In determining the 5-year period, I relied on the Company's prior rate case applications with the ND Commission which reflected electric rate case filings in 2001, 2004, 2006 and 2021. (Data Response 1-23). The Company has filed rate case petitions on average every five-years. I normalized the period between rate cases (2001-2021) and arrived at an average 5-year period between rate cases. This results in an annual recovery of $5,590. This is shown on Schedule DM-21.

b). NOL ADIT ARAM - $22,547

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS NET OPERATING LOSS, ACCUMULATED DEFERRED INCOME TAXES, AVERAGE RATE ASSUMPTION METHOD OF $22,547?

A. The Company is proposing to amortize the NOL ADIT ARAM over a 23-year period. The Commission's Order in PU-18-156 approved the Company's proposed amortization level included in the Tax Cuts and Jobs Act (TCJA) refund calculation. (Exhibit BCH-1 testimony page 39). (WP A16).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's proposal related to the $22,547 amortization expense related to the NOL ADIT ARAM. My adjustment is shown on Schedule DM-21.

c). Rate Case Expenses $408,115

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS RATE CASE EXPENSES?

A. The Company has proposed to recover about $1.224 million ($1.224 million / 3 three years or $408,000) of projected direct costs associated with this rate case docket and a three-year amortization period. (Exhibit BCH-1 testimony page 40). (WP A17).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's proposed rate case expense balance of $1.224 million. My only adjustment is to extend the amortization period to 5 years consistent with my recommended amortization period for other amortizations in this rate proceeding. This reduces the expense from $408,115 to $244,869, a reduction of $163,246. My adjustment is shown on Schedule DM-21.

N. Taxes Other Than Income Taxes

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO TAXES OTHER THAN INCOME TAXES?

A. As shown on Company Exhibit Schedule 3A page 2 of 6, and in Exhibit BCH-1 Schedule 6, the Company proposed total Taxes other Than Income Taxes of \$2,401,000.[3] The breakdown representing the balance is as follows:

a).	Property Taxes – Net	\$1,587,000
b).	Deferred Income Taxes	\$ 550,000
c).	Payroll – (Adj.)	\$ 263,000
	Total	**\$ 2,401,000**

a). Property Taxes – Net - \$1,587,442

Q. HOW DID THE COMPANY DEVELOP ITS PROPERTY TAX BALANCE OF \$1,587,000?

A. In response to Public Data Request 1-24, the Company is allocated a portion of its Property Taxes from NSPM-Minnesota. The North Dakota Office of the State Tax Commissioner's provides property tax valuation and assessment calculations for 2019, 2020 and 2021. **(These valuation reports are deemed confidential).** The Company's Property Taxes reflect what has been allocated to North Dakota including some plant in Minnesota. These valuations do not reflect the full amount of property taxes included in rates.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY PROPERTY TAX BALANCE?

A. I am recommending averaging out Property Taxes for the periods 2019-2021 and normalizing these costs. The allocations between and among the NSPM Minnesota vary from year to year as shown in the Attached NDPSC Data Request No. 1-024 Attachment A. Therefore, given that the allocations do change from year to year, it may not appear at face value that Property Taxes are increasing from year to year. In the response to the non-confidential Data Response 1-24 the Company's recorded Property Taxes in 2019 were \$1,301,677. In Company Exhibits BCH-1 Schedules 3C, 3B and 3A, the Company recorded \$1,190,489 of

[3] Any differences due to rounding.

Property Taxes in 2020, $1,283,706 of Property Taxes in 2021 and $1,587,442 of Property Taxes in the 2022 test year period. Given the fluctuations from year to year, I believe it is appropriate to normalize these costs. The three year average calculates to $1,258,624, (2019 – 2021 Property Tax balances) a reduction of $328,818 from the Company's proposed balance of $1,587,442. My recommendation is shown on my Schedule DM-22.

b). Deferred Income Taxes - $551,000

Q. HOW DID THE COMPANY DEVELOP ITS DEFERRED INCOME TAXES ADJUSTMENT OF $551,000?

A. According to Mr. Halama's testimony (BCH-1) page 25, the Company determined income taxes based on total before book income, tax additions, and deductions which determine deferred income taxes and the resulting taxable income that is used to calculate federal and state income taxes. The Federal Income Tax rate reflects the 21% rate effective January 1, 2018 with the enactment of the TJCA. Mr. Halama stated that net operating losses (NOL) are created when taxable deductions exceed taxable revenues, and when this occurs, the excess deductions are carried forward to future periods. (Halama Testimony BCH-1 page 26). The NOL required an adjustment that offsets the part of the ADIT rate base reduction that is associated with the accelerated depreciation deductions, which is needed to keep the Company's rate base consistent with the income tax deductions that the Company has been able to use. Keeping a balance of rate base reductions from the ADIT and the use of accelerated depreciation is required under Federal income tax law and part of normalization for both accounting and ratemaking. (Halama Testimony BCH-1 page 26).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S DEFERRED INCOME TAXES AND ITC BALANCE?

A. I am accepting the Company balance related to its Deferred Tax balance of $551,000. Since I did not make any adjustments to the Company's proposed

Depreciation Study – Remaining Life and Depreciation Study TD&G, I have no adjustments within these categories.

c). <u>Payroll – (Adj.) $263,000</u>

Q. WHAT IS YOUR THIRD ADJUSTMENT PAYROLL TAXES?

A. Since I made adjustments to the Company's Labor balance, and Incentive Compensation I am making the associated adjustment to the Company's Payroll Taxes and Others. I utilized the Company's O&M Labor assigned to the North Dakota jurisdiction (NDPSC 1-34 Attachment A) of $4,093,208 and the Company's proposed Payroll of $262,844 to arrive at a 6.421% ratio. I then took my adjustments to Labor and Incentive Compensation and multiplied the balance by 6.421% to arrive at a Payroll adjustment of $12,935.

Q. WHAT IS YOUR TOTAL ADJUSTMENT RELATED TO THE COMPANY'S TAXES OTHER THAN INCOME TAXES?

A. My adjustment is a decrease of $341,753. This is shown on Schedule DM-22.

<u>O. State Income Taxes</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS STATE INCOME TAXES?

A. The Company proposed a State Income Tax Expense of $275,243 (Schedule DM-23). This is comprised of Current State Income Taxes of ($29,000) and Proposed State Income Taxes of $304,243, shown on Exhibit BCH-1 Schedule 3A.

Q. HOW DID THE COMPANY COMPUTE ITS STATE INCOME TAX?

A. The Company computed its State Income Taxes by using the Statutory State Tax Rate of 4.31% (Exhibit BCH-1 Revised Schedule 3A) and multiplying that rate by the proposed Revenue Requirement of $7,059,000 to arrive at a balance of $304,243. (Company Exhibit BCH-1 Schedule 11).

Q. HOW DID YOU COMPUTE YOUR STATE INCOME TAXES FOR PURPOSES OF THIS PROCEEDING?

A. I utilized the Company's methodology, and the flow-throughs of my adjustments to Operating Revenues, Operating Expenses, Depreciation and Amortization Expense, and Rate Base related adjustments, to compute my recommended State Income Tax adjustment.

Q. WHAT IS YOUR STATE INCOME TAX EXPENSE?

A. My proposed State Income Tax Expense is $99,883, which is calculated by taking my recommended revenue requirement of $2,990,332 and multiplying that amount by 4.31% to arrive at a balance of $128,883. My total State Income Taxes is $99,883 shown on my Schedule DM-23. The additional State Income Tax is incorporated into my revenue requirement Schedule DM-1 through the Gross Revenue Conversion Factor of 1.322840.

P. Federal Income Taxes

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS FEDERAL INCOME TAXES?

A. The Company has proposed a Federal Income Tax Expense of $1,283,499. This is comprised of current Federal Income Taxes of ($135,000) and proposed Federal Income Taxes of $1,418,499 shown on Company Exhibit BCH-1 Schedule 3A.

Q. HOW DID THE COMPANY COMPUTE ITS FEDERAL INCOME TAX EXPENSE?

A. The Company computed its Federal Income Taxes by using the Statutory Federal Tax Rate of 21.00% (Exhibit BCH-1 Revised Schedule 3A) and multiplying that rate by the Company's proposed Revenue Requirement of $7,059,000 to arrive at a balance of $1,418,499.

Q. HOW DID YOU COMPUTE YOUR FEDERAL INCOME TAXES FOR PURPOSES OF THIS PROCEEDING?

A. As I calculated the Company's State Income Taxes, I have used the same methodology to calculate the Company's Federal Income Taxes. Using my recommended Revenue Requirement increase of $2,990,332, I multiplied that amount by 21% to arrive at a proposed Income Tax Expense of $600,904.

Q. WHAT IS YOUR FEDERAL INCOME TAX EXPENSE?

A. My proposed Federal Income Tax Expense is $465,904. This is shown on my Schedule DM-23. My total proposed balance of $465,904 includes the Company's current balance of ($135,000). The additional Federal Income Tax is incorporated into my revenue requirement Schedule DM-1 through the Gross Revenue Conversion Factor of 1.322840.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does. I reserve the right to amend my direct testimony in the event other information becomes forthcoming, subsequent to the filing of this testimony.

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule DM-1

REVENUE REQUIREMENT

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Average Rate Base**	**$ 124,227,000**	**$ (1,695,902)**	**$ 122,531,098**	
2	Present Rate Income	$ 3,919,000	$ 2,224,449	$ 6,143,449	
3	AFUDC	$ -		$ -	
4	**Total Available for Return**	**$ 3,919,000**	$ 2,224,449	**$ 6,143,449**	
5	Present Rate of Return	3.155%		5.014%	
6	Required Return	7.450%		6.86%	
7	**Operating Income Requirement**	**$ 9,254,912**	**$ (850,924)**	**$ 8,403,988**	
8	**Income Deficiency**	**$ 5,335,912**	**$ (3,075,372)**	**$ 2,260,539**	
9	Gross Revenue Conversion Factor	1.322840		1.322840	(2)
10	**Revenue Deficiency**	**$ 7,058,557**	**$ (4,068,225)**	**$ 2,990,332**	
11	Present Rate Revenues	$ 67,303,000		$ 67,302,687	
12	Percentage Increase	10.488%		4.443%	
	Total Revenue Requirement			**$ 70,293,019**	

(1) Company Exhibit BCH-1 Schedule 7
(2) Company Exhibit BCH-1 Schedule 3A

State Income Tax Rate	4.310000%
Federal Income Tax Rate	21.000000%
Effective Tax Rate	20.090000%
Composite Tax Rate	**24.400000%**
Revenue Conversion Factor	**1.322837**

Differences due to rounding

WEIGHTED AVERAGE COST OF CAPITAL

(1) Company Proposed

		Ratios	Cost of Capital	Weighted Average
1	LT Debt	47.03000%	4.09550%	1.92611%
2	ST Debt	0.43000%	1.09000%	0.00469%
3	Common Equity	52.54000%	10.50000%	5.51670%
4	**Total Capital**	**100.00000%**		**7.44750%**
5	rounded			7.45000%

(2) ND PSC Advocacy Staff

		Ratios	Cost of Capital	Weighted Average
6	LT Debt	47.570%	4.100%	1.950%
7	ST Debt	0.430%	1.090%	0.005%
8	Common Equity	52.000%	9.430%	4.904%
9	**Total Capital**	**100.000%**		**6.86%**

(1) Company WP C1
(2) Exhibit MFG-16

Northern States Power Co. ND - Gas
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ND Public Service Commission
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Schedule DM-3

AVERAGE RATE BASE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Gas Plant in Service				
1	Production	$ 5,340,000	$ -	$ 5,340,000	
2	Transmission	$ 3,909,000	$ -	$ 3,909,000	
3	Distribution	$ 181,046,000	$ (607,617)	$ 180,438,383	
4	Gas Storage	$ 9,341,000	$ -	$ 9,341,000	
5	General	$ 14,757,000	$ -	$ 14,757,000	
6	Common	$ 8,463,000	$ -	$ 8,463,000	
7	**Total Gas Plant In Service**	**$ 222,856,000**		**$ 222,248,383**	
8	Depreciation Reserve	$ 82,973,000	$ (16,078)	$ 82,956,922	
9	**Net Gas Plant In Service**	**$ 139,883,000**	**$ (591,539)**	**$ 139,291,461**	
10	Gas Plant Held for Future Use	$ -	$ -	$ -	
11	Construction Work in Progress	$ 188,000	$ -	$ 188,000	
12	**Accumulated Deferred Income Taxes**	**$ 19,783,000**	**$ (4,376)**	**$ 19,778,624**	
13	Cash Working Capital	$ 648,000	$ (1,086,738)	$ (438,738)	
14	**Subtotal**	**$ 120,936,000**	**$ (1,673,902)**	**$ 119,262,098**	
	Other Rate Base Items				
15	Materials and Supplies	$ 150,000	$ -	$ 150,000	
16	Fuel Inventory	$ 2,098,000	$ -	$ 2,098,000	
17	Non-Plant Assets & Liabilities	$ 1,463,000	$ -	$ 1,463,000	
18	Customer Advances	$ (1,340,000)	$ -	$ (1,340,000)	
19	Customer Deposits	$ (42,000)	$ -	$ (42,000)	
20	Prepaids and Other	$ 523,000	$ -	$ 523,000	
21	Regulatory Amortization - ITT/ADIT ARAM	$ 440,000	$ (23,000)	$ 417,000	WP A15
22	**Total Other Rate Base Items**	**$ 3,292,000**	**$ (23,000)**	**$ 3,269,000**	NDPSC 1-32
23	**Total Average Rate Base**	**$ 124,228,000**	**$ (1,696,902)**	**$ 122,531,098**	

(1) Company Exhibit BCH-1 Schedule 15

differences due to rounding

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
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Schedule DM-4

OPERATING INCOME STATEMENT

		(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	Present Rates ND PSC Advocacy Staff	References
	Operating Revenues						
1	Retail Revenues	$ 67,303,000	$ 7,059,000	$ 74,362,000	$ -	$ 67,302,687	
2	Interdepartmental	$ -		$ -	$ -	$ -	
3	Other Operating	$ 550,000	$ -	$ 550,000	$ -	$ 550,384	
4	**Total Operating Revenues**	**$ 67,853,000**	**$ 7,059,000**	**$ 74,912,000**	**$ -**	**$ 67,853,071**	DM-9
	Operating Expenses						
5	Purchased Gas	$ 43,934,000		$ 43,934,000	$ -	$ 43,934,429	DM-12
6	Gas Production & Storage	$ 635,000		$ 635,000	$ -	$ 635,473	DM-13
7	Gas Transmission	$ 387,000		$ 387,000	$ (44,477)	$ 342,523	DM-14
8	Gas Distribution	$ 5,129,000		$ 5,129,000	$ (1,146,821)	$ 3,982,179	DM-15
9	Customer Accounting	$ 1,613,000		$ 1,613,000		$ 1,311,454	DM-16
10	Customer Service & Other	$ 149,000		$ 149,000	$ 10,771	$ 159,771	DM-17
11	Sales, Econ Development & Other	$ 10,000		$ 10,000	$ (7,645)	$ 2,355	DM-18
12	Administrative & General	$ 2,508,000		$ 2,508,000		$ 2,471,170	DM-19
	Vacancy Rate Adjustment				$ (173,413)	$ (173,413)	1-34/20/17
13	**Total Operating Expenses**	**$ 54,365,000**	**$ -**	**$ 54,365,000**	**$ (1,699,058)**	**$ 52,665,942**	
14	Depreciation Expense	$ 6,892,000	$ -	$ 6,892,000	$ (16,873)	$ 6,875,127	DM-20
15	Amortization Expense	$ 440,000	$ -	$ 440,000	$ (166,994)	$ 273,006	DM-21
16	Taxes Other Than Income	$ 2,401,000		$ 2,401,000	$ (341,453)	$ 2,059,547	DM-22
17	State Income Taxes	$ (29,000)	$ 304,243	$ 275,243	$ -	$ (29,000)	DM-23
18	Federal Income Taxes	$ (135,000)	$ 1,418,499	$ 1,283,499	$ -	$ (135,000)	DM-23
19	**Total Taxes**	**$ 2,237,000**	**$ 1,722,742**	**$ 3,959,742**	**$ (341,453)**	**$ 1,895,547**	
20	**Total Expenses**	**$ 63,934,000**	**$ 1,722,742**	**$ 65,656,742**	**$ (2,224,378)**	**$ 61,709,622**	
21	AFUDC	$ -	$ -	$ -		$ -	
22	**Total Operating Income**	**$ 3,919,000**	**$ 5,336,258**	**$ 9,255,258**	**$ 2,224,449**	**$ 6,143,449**	
23	Rate Base	$ 124,228,000		$ 124,228,000		$ 122,531,098	
24	Rate of Return	3.155%		7.4502%		6.86%	
				$ 9,255,258		$ 8,403,988	

(1) Company Exhibit BCH-1 Schedule 11

differences due to rounding

GAS PLANT IN SERVICE

		(1) Company Proposed Unadj.	Adjustments	Company Proposed Adj.	Adjustments	ND PSC Advocacy Staff	References
1	Gas Manufactured Plant	$ 5,340,000	$ -	$ 5,340,000		$ 5,340,000	
2	Gas Storage	$ 9,341,000	$ -	$ 9,341,000		$ 9,341,000	
3	Gas Transmission	$ 3,909,000	$ -	$ 3,909,000		$ 3,909,000	
4	Gas Distribution	$ 181,046,000	$ -	$ 181,046,000	$ (607,617)	$ 180,438,383	ND PSC 1-46/49
5	General	$ 11,871,000	$ -	$ 11,871,000		$ 11,871,000	ND PSC 4-7/4-9
6	Common	$ 11,348,000	$ -	$ 11,348,000		$ 11,348,000	
7	**Total Gas Plant In Service**	**$ 222,855,000**	**$ -**	**$ 222,855,000**	**$ (607,617)**	**$ 222,247,383**	ND PSC 1-44/45

(1) Company Exhibit BCH-1 Schedule 5

Meter Installation costs - outside $3,500 x 111 - $388,500 1-46 (relocation) 1-46
Meter exchange costs $453 X 12,525 = $5,673,825 1-47
Cost to exchange a module $72 x 12,525 = $901,800 commencing in 2023 1-48
Fargo Project located in Gas Distribution
Capital Additions 1-55 and 1-56
AGIS adjustment 1-62
Wescott - Spring of 2022, Sibley - Maplewood and Delta V

ACCUMULATED DEPRECIATION

	(1) Company Unadjusted	Adjustments	Company Proposed	Adjustments	ND PSC Advocacy Staff	References
Gas Manufactured Plant	$ 2,420,000	$ (45,000)	$ 2,375,000	$ -	$ 2,375,000	WP A8
Gas Storage	$ 8,010,000	$ 29,000	$ 8,039,000	$ -	$ 8,039,000	WP A8
Gas Transmission	$ 1,683,000	$ 3,000	$ 1,686,000	$ -	$ 1,686,000	WP A9
Gas Distribution	$ 59,581,000	$ 50,000	$ 59,631,000	$ (16,078)	$ 59,614,922	WP A9
General	$ 5,559,000	$ 47,000	$ 5,606,000	$ -	$ 5,606,000	WP A9
Common	$ 5,619,000	$ 17,000	$ 5,636,000	$ -	$ 5,636,000	WP A9
Total Accumulated Depreciation	**$ 82,872,000**	**$ 101,000**	**$ 82,973,000**	**$ (16,078)**	**$ 82,956,922**	

(1) Company Exhibit BCH-1 Schedule 5

ACCUMULATED DEFERRED INCOME TAXES

		(1) Company Unadjusted	Adjustments	Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	Production	$ (77,000)	$ 12,000	$ (65,000)	$ -	$ (65,000)	WP A8
2	Transmission	$ 718,000	$ (1,000)	$ 717,000	$ -	$ 717,000	WP A9
3	Distribution	$ 17,469,000	$ (14,000)	$ 17,455,000	$ -	$ 17,455,000	WP A9
4	Gas Storage	$ (416,000)	$ (8,000)	$ (424,000)	$ (3,376)	$ (427,376)	WP A8
5	General	$ 1,266,000	$ (19,000)	$ 1,247,000	$ -	$ 1,247,000	WP A9
6	Common	$ 625,000	$ 1,000	$ 626,000	$ -	$ 626,000	WP A9
7	Net Operating Loss	$ (93,000)	$ -	$ (93,000)	$ -	$ (93,000)	
8	Non-Plant Related	$ 319,000	$ -	$ 319,000	$ -	$ 319,000	
9	**Total Accumulated Deferred Income Taxes**	**$ 19,811,000**	**$ (29,000)**	**$ 19,782,000**	**$ (3,376)**	**$ 19,778,624**	

(1) Company Exhibit BCH-1 Schedule 15

Northern States Power Co. ND - Gas
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Schedule DM-8

	CASH WORKING CAPITAL	(1) Lead/Lag Days	Company Dollars	Dollar x Days	Adjustments	ND PSC Advocacy Staff	References
1	**Fuel Expenses**	39.09119	$ 14,442,000	$ 564,554,966	$ 1,152,877,375	$ 1,717,432,341	4-3
	Labor						
2	Regular Payroll	11.890587	$ 3,409,000	$ 40,535,011	$ (173,413)	$ 38,473,031	DM-4
3	Incentive	248.81	$ 37,000	$ 9,205,970	$ (28,039)	$ 2,229,586	
4	Pension & Benefits	37.23	$ 647,000	$ 24,087,810	$ -	$ 24,087,810	
			$ 4,093,000	**$ 73,828,791**	**$ (9,038,364)**	**$ 64,790,427**	
5	All Other Operating Expenses	22.73988	$ 37,080,000	$ 843,194,750		$ 202,496,941	4-3
6	Property Taxes	357.9199	$ 1,587,000	$ 568,018,881		$ 450,486,576	
7	Employer's Payroll Taxes	31.6197	$ 263,000	$ 8,315,981		$ 7,902,041	
8	Gross Earnings Tax	38.8962	$ 1,214,000	$ 47,219,987		$ 47,219,987	
9	Federal Income Taxes	37.005	$ (386,000)	$ (14,283,930)		$ (4,995,675)	
10	State Income Taxes	36.9156	$ (83,000)	$ (3,063,995)		$ (1,070,552)	
			$ 39,675,000	**$ 1,449,401,675**		**$ 702,039,317**	
11	**Total**		**$ 58,210,000**	**$ 2,087,785,432**		**$ 2,484,262,086**	
12	Net Annual Expense (365)			$ 5,719,960		$ 6,806,197	
13	Revenues	40.2998	$ 67,303,000	$ 2,712,297,439		$ 2,712,284,826	
14	Late Payment		$ 155,000	$ -		$ -	
15	Miscellaneous Services	40.389	$ 118,000	$ 4,765,902		$ 4,765,902	
16	Rentals	-50.009	$ 211,000	$ (10,551,899)		$ (10,551,899)	
17	**Total**		**$ 67,787,000**	**$ 2,706,511,442**		**$ 2,706,498,829**	
18	Net Annual Amount (365)			$ 7,415,100		$ 7,415,065	
19	Expense/Revenue Factor			85.87%		85.87%	
20	Allocated Revenue			$ 6,367,489		$ 6,367,459	
21	**Net Cash Working Capital**			**$ 647,529**		**$ (438,738)**	

(1) Company Exhibit BCH-1 Schedule 8

Northern States Power Co. ND - Gas
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Schedule DM-9

OPERATING REVENUES

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	Residential Service	$ 26,797,199	$ -	$ 26,797,199	
2	Commerical/Industrial	$ 31,901,891	$ -	$ 31,901,891	
3	Small Interruptible Service	$ 2,194,889	$ -	$ 2,194,889	
4	Large Interruptible Service	$ 6,408,708	$ -	$ 6,408,708	
5	Interruptible	$ -	$ -	$ -	
6	Firm Transportation Service	$ -	$ -	$ -	
7	**Total Present Rate Revenues**	**$ 67,302,687**	**$ -**	**$ 67,302,687**	
8	Other Gas Revenues	$ 550,384	$ -	$ 550,384	1-33
9	**Total Operating Revenues**	**$ 67,853,071**	**$ -**	**$ 67,853,071**	

(1) Company WP R2 Present Revenues
Differences due to rounding

Northern States Power Co. ND - Gas
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Schedule DM-10

OPERATION & MAINTENANCE EXPENSES - WORKSHEET

	Three-Year Normalize Non-Labor	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	Purchased Gas Expense	$ 43,934,429	$ -	$ 43,934,429	DM-12
2	Gas Production & Storage	$ 289,489	$ -	$ 289,489	DM-13
3	Gas Transmission	$ 304,359	$ (44,169)	$ 260,190	DM-14
4	Gas Distribution	$ 3,278,109	$ (901,253)	$ 2,376,856	DM-15
5	Customer Accounting	$ 1,217,726	$ (301,166)	$ 916,560	DM-16
6	Customer Service & Information	$ 140,217	$ 11,853	$ 152,070	DM-17
7	Sales, Econ Develop & Other	$ 8,872	$ -	$ 8,872	DM-18
8	Administrative & General	$ 1,099,071	$ -	$ 1,099,071	DM-19
9	**Total**	**$ 50,272,272**	**$ (1,234,735)**	**$ 49,037,537**	

(1) Company WP O2-3 Jurisdictional Alloc.
Diffferences due to rounding

check for vacancy rate - 1-17 and 1-15
check for hires in 1-19 - trade secret for salaries
review 1-34 without labor

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule DM-12

PURCHASED GAS

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 43,934,429**		**$ 43,934,429**	
2	Adjustments	$ -		$ -	
3	Precedential Adjustments	$ -		$ -	
4	**Adjusted Balance**	**$ 43,934,429**	**$ -**	**$ 43,934,429**	

(1) Company Schedule BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation

GAS PRODUCTION & STORAGE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 635,473**		**$ 635,473**	
2	Adjustments	$ -	$ -	$ -	ND PSC 4-12
3	Precedential Adjustments	$ -	$ -	$ -	
4	**Adjusted Balance**	**$ 635,473**		**$ 635,473**	ND PSC 1-51

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation
Wescott, Maplewood & Sibley Plants

Northern States Power Co. ND - Gas
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Schedule DM-14

GAS TRANSMISSION

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 386,692**		**$ 386,692**	
2	Adjustments - three year average	$ -	$ (44,169)	$ (44,169)	ND PSC 1-34
	Damage Prevention Program	$ -	$ -	$ -	ND PSC 1-53
3	Precedential Adjustments	$ -	$ -	$ -	
4	**Adjusted Balance**	**$ 386,692**	**$ (44,169)**	**$ 342,523**	

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation

GAS DISTRIBUTION

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance				
1	G Customer MNND Border	$ 2,258,174	$ (775,305)	$ 1,482,869	ND PSC 4-13
2	G Customers	$ 947,014	$ 168,496	$ 1,115,510	
3	G Direct MN	$ -	$ -	$ -	
4	G Direct ND	$ 1,924,193	$ (294,443)	$ 1,629,750	
5	**Total Balance**	**$ 5,129,381**	**$ (901,252)**	**$ 4,228,129**	ND PSC 1-50
6	Damage Prevention Program	$ -	$ (245,950)	$ (245,950)	ND PSC 1-53
7	Precedential Adjustments	$ -	$ -	$ -	
8	**Adjusted Balance**	**$ 5,129,381**	**$ (1,147,202)**	**$ 3,982,179**	

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation
Fargo Capacity Cost - O&M $18,000 plus $4,600

CUSTOMER ACCOUNTING

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance				
1	G Bad Debts	$ 280,729	$ 4,204	$ 284,933	ND PSC 4-14
2	G Customers	$ 932,545	$ (191,159)	$ 741,386	
3	G Direct MN	$ -	$ -	$ -	
4	G Direct ND	$ 399,447	$ (114,312)	$ 285,135	
5	**Total Balance**	**$ 1,612,721**	**$ (301,267)**	**$ 1,311,454**	
6	Adjustments	$ -	$ -	$ -	
7	Precedential Adjustments	$ -	$ -	$ -	
8	**Adjusted Balance**	**$ 1,612,721**	**$ (301,267)**	**$ 1,311,454**	

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation
Meter reading costs - 1-48

Northern States Power Co. ND - Gas | ND Public Service Commission | Schedule DM-17
Test Year Ending 12/31/2022 | Case No. PU-21-381

CUSTOMER SERVICE & INFORMATION

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance				
1	G Customers	$ 51,713		$ 51,713	ND PSC 1-34
2	G Direct ND	$ 97,676		$ 97,676	
3	Advertising	$ 40,000		$ 40,000	
4	**Total Unadjusted Balance**	**$ 189,389**	**$ -**	**$ 189,389**	
	Adjustments	$ -	$ 11,853	$ 11,853	DM-10
5	Precedential Adjustments	$ (40,000)	$ (1,471)	$ (41,471)	WP A1 Adv
6	**Adjusted Balance**	**$ 149,389**	**$ 10,382**	**$ 159,771**	ND-PSC 1-39

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation

SALES & ECONOMIC DEVELOPMENT

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
Unadjusted Balance				
G Customers	$ 2,355		$ 2,355	
Total Unadjusted Balance	**$ 2,355**	$ -	**$ 2,355**	
Adjustments	$ -	$ -	$ -	ND PSC 1-34
				WP A11 Econ.
Precedential Adjustments	$ 7,382	$ (7,382)	$ -	Donations 1-41
Adjusted Balance	**$ 9,737**	**$ (7,382)**	**$ 2,355**	

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule DM-19

ADMINISTRATIVE & GENERAL

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance				
1	G Customers MNND Border	$ 226,813	$ -	$ 226,813	ND PSC 1-34
2	G Customers MNND Border	$ 2,222,388	$ -	$ 2,222,388	
3	G Direct ND	$ 58,455	$ -	$ 58,455	
4	Other	$ 130,846	$ -	$ 130,846	
5	**Total Unadjusted Balance**	**$ 2,638,502**	**$ -**	**$ 2,638,502**	
6	Adjustments - Other	$ -	$ -	$ -	ND PSC 1-34 1-25/26
	Precedential Adjustments:				
7	Advertising	$ (28,856)	$ -	$ (28,856)	WP A1 Adv. 1-39
8	Customer Deposits	$ 676	$ -	$ 676	WP A3
9	Incentive Pay	$ (17,013)	$ -	$ (17,013)	WP A4
10	Incentive Pay LT	$ (97,348)	$ -	$ (97,348)	WP A5
11	SERP	$ (3,027)	$ -	$ (3,027)	WP A6
12	**Total Precedential Adjustments**	**$ (145,568)**	**$ -**	**$ (145,568)**	
	RM Adjustments				
13	Aviation (100%)	$ (22,003)	$ -	$ (22,003)	WP A7
14	Chamber of Commerce	$ 2,221	$ (2,221)	$ -	WP A10 - 1-40
15	Economic Develop Donations	$ 6,226	$ (6,226)	$ -	WP A12 1-42
16	Incentive Pay - Environmental LTI	$ 17,060	$ (17,060)	$ -	WP A13
17	Incentive Pay - Time Based LTI	$ 10,979	$ (10,979)	$ -	WP A14
18	**Total RM Adjustments**	**$ 14,483**	**$ (36,486)**	**$ (22,003)**	
19	**Adjusted Balance**	**$ 2,507,417**		**$ 2,470,931**	
20	rounding	$ 239		$ 239	
21	**Total**	**$ 2,507,656**	**$ (36,486)**	**$ 2,471,170**	

(1) Company Exhibit BCH-1 Schedule 6
Company O2-3 Jurisditional Allocation
Company Exhibit BCH-1 Schedule 4

Review data responses to 1-6, 1-13, 1-14, 1-15, 1-16, 1-17
Confirm total Gas Employees and the allocate employees who left

DEPRECIATION EXPENSE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 6,845,000**	**$ (16,078)**	**$ 6,828,922**	1-43/4-9
	Remaining Life				
2	Gas Manufactured Production Plant	$ (90,872)	$ -	$ (90,872)	WP A8
3	Gas Other Storage Plant	$ 58,954	$ -	$ 58,954	WP A8
4	**Total Remaining Life**	**$ (31,918)**	**$ -**	**$ (31,918)**	
	Depreciation Study				
5	Gas Distribution - Composite 2.646%	$ 33,481	$ -	$ 33,481	WP A9
6	Gas Transmission - Composite 1.76%	$ 1,767	$ -	$ 1,767	WP A9
7	Common-General - AGIS - 21.68%	$ 17,742	$ -	$ 17,742	WP A9
8	General	$ 27,897	$ -	$ 27,897	WP A9
9	Common-Intangible	$ (6,212)	$ -	$ (6,212)	WP A9
10	Intangible	$ 3,448	$ -	$ 3,448	WP A9
11	**Total Depreciation Study**	**$ 78,123**	**$ -**	**$ 78,123**	
12	**Adjusted Balance**	**$ 6,891,205**	**$ (16,078)**	**$ 6,875,127**	

(1) Company Exhibit BCH-1 Schedule 6
Fargo Project located in Gas Distribution
refer to 1-43, updated in Company
Refer to 1-61/63

AMORTIZATION EXPENSE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance	**$ -**			
(2)	Income Tax Tracker	$ 9,317	$ (3,727)	$ 5,590	WP A15
	NOL Tax Reform ADIT ARAM	$ 22,547	$ -	$ 22,547	WP A16
(3)	Rate Case Expense Amortization	$ 408,115	$ (163,246)	$ 244,869	WP A17
	Adjusted Balance	**$ 439,979**	**$ (166,973)**	**$ 273,006**	

(1) Company Exhibit BCH-1 Schedule 6

Refer to 1-43 - updated in Company Rebuttal

(2) Income Tax Tracker amortized over 5 years

(3) Rate Case Expense amortized over 5 years

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule DM-22

TAXES OTHER THAN INCOME

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
Property Taxes	**$ 1,587,442**	**$ (328,818)**	**$ 1,258,624**	1-24
Payroll Taxes	**$ 262,844**	**$ (12,935)**	**$ 249,909**	1-34
Unadjusted Deferred Income Taxes / ITC	**$ 564,000**	**$ -**	**$ 564,000**	
Depreciation Study - Remaining Life				
Gas Manufactured Plant	$ 25,543	$ -	$ 25,543	
Gas Other Storage Plant	$ (16,571)	$ -	$ (16,571)	
Total	**$ 8,972**	**$ -**	**$ 8,972**	WP A8
Depreciation Study - TD&G - 28.11%				
Gas Distribution	$ (9,410)	$ -	$ (9,410)	
Gas Transmission	$ (497)	$ -	$ (497)	
Common-General	$ (4,987)	$ -	$ (4,987)	
General	$ (7,841)	$ -	$ (7,841)	
Common-Intangible	$ 1,746	$ -	$ 1,746	
Intangible Plant	$ (969)	$ -	$ (969)	
Total	**$ (21,958)**	**$ -**	**$ (21,958)**	WP A9
Adjusted Deferred Income Taxes/ITC	**$ 551,014**	**$ -**	**$ 551,014**	
Total Taxes Other Than Income	**$ 2,401,300**	**$ (341,753)**	**$ 2,059,547**	

(1) Company Exhibit BCH-1 Schedule 6

STATE INCOME TAXES
FEDERAL INCOME TAXES

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
State Income Taxes				
Current - 4.31%	$ (29,000)	$ -	$ (29,000)	NDPSC 1-38
Proposed Revenue Requirement	$ 7,059,000		$ 2,990,332	
Proposed State Income Taxes	$ 304,243		$ 128,883	
Proposed Balance	**$ 275,243**		**$ 99,883**	
Federal Income Taxes				
Current - 21%	$ (135,000)	$ -	$ (135,000)	NDPSC 1-38
Proposed Revenue Requirement	$ 7,059,000		$ 2,990,332	
Proposed Federal Income Taxes	$ 1,418,499		$ 600,904	
Proposed Balance	**$ 1,283,499**		**$ 465,904**	
Check total	$ 1,558,742		$ 565,788	

(1) Company Exhibit BCH-1 Schedule 3A
Differences due to rounding

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
2021 Natural Gas Rate Increase
Application

Case No. PU-21-381

Verification

State Of New Jersey)
) ss.
County Of Ocean)

Dante Mugrace, being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matters under his name, that they were prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

Dante Mugrace
Dante Mugrace

Subscribed and sworn to before me this 28 day of February, 2022.

Notary Public
My Commission Expires: May 22, 2026

REBECCA RAIMONDO
Notary Public - State of New Jersey
My Commission Expires May 22, 2026